Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2002* (*AEO2002*) are based on Federal, State, and local laws and regulations in effect on September 1, 2001. The potential impacts of pending or proposed legislation, regulations, and standards—and sections of existing legislation requiring funds that have not been appropriated—are not reflected in the projections.

Federal legislation incorporated in the projections includes the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels [*1*]; the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; the Tax Payer Relief Act of 1997; the Federal Highway Bill of 1998, which included an extension of the ethanol tax incentive; new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions; and the new standards for energy-consuming equipment that were announced in 2001. *AEO2002* assumes the continuation of the ethanol tax incentive through 2020. *AEO2002* also assumes that State taxes on gasoline, diesel, jet fuel, M85, and E85 will increase with inflation and that Federal taxes on those fuels will continue at 2000 levels in nominal terms. Although the above tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2002* assumes their continuation throughout the forecast.

AEO2002 also incorporates regulatory actions of the Federal Energy Regulatory Commission (FERC), including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets, and other FERC actions to foster more efficient natural gas markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted. As of July 1, 2001, 24 States and the District of Columbia had passed legislation or promulgated regulations to restructure their electricity markets. The projections include recently announced delays in restructuring in several States. In California, retail competition has been suspended.

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, there is a phased reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NO_x) emissions; the forecast includes NO_x caps for States where they have been finalized. The impacts of CAAA90 on electricity generators are discussed in "Market Trends" (see page 100).

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided. A discussion of the status of efficiency standards is included later in this section.

Energy combustion is the primary source of anthropogenic (human-caused) carbon dioxide emissions. *AEO2002* estimates of emissions do not include emissions from activities other than fuel combustion, such as landfills and agriculture, nor do they take into account "sinks" that absorb carbon dioxide, such as forests.

The *AEO2002* reference case projections include analysis of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. CCAP was formulated as a result of the Framework Convention on Climate Change, which was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992. As part of the Framework Convention, the economically developed signatories, including the United States, agreed to take voluntary actions to reduce emissions to 1990 levels. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the analysis.

Although CCAP did not achieve the goal of reducing greenhouse gas emissions to 1990 levels by 2000 and no longer exists as a unified program, most of the individual programs, which are generally voluntary, remain. The impacts of those programs are included in the projections. The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto Protocol, which was agreed to on December 11, 1997, but has not been ratified, or other international agreements. The Kyoto Protocol, for which the Bush Administration has announced it will not seek ratification, and the status of international negotiations on climate change are discussed later in this section.

Electricity Markets: State Restructuring and the California Energy Crisis

Some States Step Back from Restructuring Plans

California formally ended competition (direct access) in its retail electricity market in September 2001, after a year and a half of very high wholesale prices exposed market design failures, forced competitive suppliers from the market, raised retail prices, and caused the bankruptcy of the State's largest utility [*2*]. California's energy crisis has led some States that were in the process of implementing electricity market restructuring legislation to postpone implementation and has forced other States in the process of negotiating the terms of restructuring legislation to rethink their priorities. The biggest fear among the States is that inadequate supply will allow a few suppliers to assert market power and raise prices beyond acceptable levels. States are also considering whether their transmission capacity is adequate to ensure a viable marketplace, and how to give electricity consumers more options for responding to price signals.

In March 2001, Nevada, New Mexico and Arkansas delayed the opening of their retail electricity markets to competition. Nevada's Governor halted the implementation of electric utility deregulation indefinitely—until such time as "the market stabilizes, adequate consumer protections are in place, and supply is at an acceptable level." New legislation in Nevada has re-regulated the State's utilities, delaying the sale of their power plants. At the same time, large customers with time-of-use meters (to be installed by the utility at the cost of the provider or customer) will be allowed to choose their suppliers and residential customers with renewable distributed generators will be offered net metering [*3*].

New Mexico enacted new legislation to delay the opening of its retail electricity market to competition until 2007. The law also delays Public Service of New Mexico's unbundling of its distribution business from its generation and marketing businesses and allows the utility to proceed with plans to build new generation capacity and form a holding company.

Arkansas put off the start of deregulation from January 2002 to October 2003. The Arkansas Public Service Commission (PSC) is also authorized to initiate further delays based on the adequacy of the State's transmission system and generating capacity to support a competitive market. The PSC issued a request for utilities to provide an analysis of prices customers may pay for electric generation service under open access as compared with continued regulation, and to provide the information needed to evaluate the readiness of both retail and wholesale markets for implementation of retail open access.

Legislation was enacted to revise Oregon's restructuring law in August 2001, delaying the date for implementing retail access for large customers from October 2001 to March 2002. Most other provisions of Oregon's plans for restructuring were also delayed for 6 months to March 2002, including allowing residents to choose from a portfolio of retail options.

In June 2001, Oklahoma delayed retail competition. New legislation established a nine-member task force to study the effects of deregulation. Competition, originally scheduled to be phased in from January 2002 to January 2004, will be put off until (1) the task force issues its final report, not later than December 2002, and (2) the legislature enacts enabling restructuring legislation.

In November 2000, the Montana Public Service Commission delayed the date for instituting complete retail access for all consumers from July 2002 to July 2004, because the State does not have a competitive power supply market in place. Most rural electric cooperatives have opted not to restructure or offer retail choice. Also, Montana Power customers have not been switching to retail choice in large numbers.

In light of the low cost of electricity in West Virginia and the price spikes that occurred this past summer in other States that have restructured retail markets, legislation was passed in October 2000 to require the 2001 West Virginia Legislature to pass a resolution before the provisions of the restructuring law can take effect. Consumer choice was to have started in January 2001. As of October 2001, no resolution had been passed.

North Carolina's legislation study panel decided in January 2001 that more study of restructuring issues was needed before recommending that the legislature open the State to competition by 2005, as previously recommended. The studies will focus on consumer protections and ways to encourage power plant construction in the State. In December 2000, the North Carolina Public Utilities Commission (PUC) staff recommended a limited deregulation plan to a legislative panel. In light of California's experience, the PUC recommended that restructuring in North Carolina proceed slowly and with caution.

In Other States, Restructuring Moves Ahead

Although many States delayed restructuring plans, others forged ahead by implementing restructuring on time or improving market designs to increase the competitiveness of their markets. Arizona, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island had full or partial competitive retail markets in place before 2001 and are proceeding as scheduled with full implementation of their restructuring plans.

Both the District of Columbia and Ohio began allowing customers direct access to competitive electricity suppliers on January 1, 2001, as mandated by restructuring legislation. Also in January 2001, the New Hampshire Supreme Court upheld New Hampshire's restructuring plan, clearing the way for competition to begin for the majority of consumers in April 2001.

Texas was still set to start full retail competition by January 2002, although pilot programs got started two months late. In September 2001, utilities in Texas began the process of auctioning part of their generating capacity. Restructuring legislation requires each generation company affiliated with a former monopoly utility to sell at least 15 percent of its installed generation capacity at least 60 days before full retail competition begins.

Pennsylvania amended its restructuring rules to allow competitive suppliers to bid for default customers, in order to ensure that more suppliers will stay in the market. In January 2001, as required under the Philadelphia Electric Company (PECO) restructuring plan, 300,000 residential customers who had not chosen a competitive supplier were randomly chosen and switched to The New Power Company, which was chosen by PECO to provide "Competitive Discount Service" from March 2001 through January 2004. Customers may opt out of the program or choose another electricity supplier without penalty.

In March 2001, Virginia passed legislation allowing competitive suppliers to bid to supply "last resort" customers—those customers without access to other competitive retail options. In July 2001, the Virginia State Corporation Commission adopted rules to advance a competitive energy supply market and protect customers who shop for alternative electricity suppliers when the retail market opens—on time—in January 2002.

The New York PSC spent 2001 fine-tuning its competitive market design. In March, the bill credit (shopping credit) a customer could receive for switching to a lower cost supplier was increased to encourage more suppliers to enter the market. The new shopping credit is tied to the going market price to make it easier for suppliers to deal with fluctuating wholesale prices. It also includes a small amount to cover administrative costs. The old shopping credit, which had been set below market prices, discouraged suppliers from entering the market. In June, the PSC approved standards governing the electronic exchange of routine business information and data among electricity and natural gas service providers in New York. The PSC also issued an order in June to establish uniform retail access billing and payment processing practices that will facilitate a single-bill option for customers who buy power and/or natural gas from energy service companies. The orders are designed to facilitate retail energy competition in New York and provide for efficient single-billing options for all New York electricity and natural gas customers.

In Washington State, a May 2001 agreement between Puget Sound and its six largest industrial customers allows them to buy power from any source. In January 2001, the Florida PSC issued a draft restructuring plan that would allow large industrial customers retail choice starting in January 2003. In March 2001, the legislatively mandated Energy 2020 Study Commission released an interim report, *Proposal for Restructuring Florida's Wholesale Market for Electricity*. The report made recommendations to the 2001 legislature that would result in the development of a competitive wholesale electricity market in Florida. Proposals included removing barriers to entry for merchant generation plants, requiring investor-owned load-serving utilities to acquire energy resources through a competitive acquisition process, and allowing utility affiliate companies to assume ownership of existing generation assets and to build new ones.

In January 2001, the Louisiana PSC issued a draft restructuring plan that would allow large industrial customers in Louisiana retail choice starting in January 2003. In March 2001, the staff of the PSC issued its final report, *Final Response of the Commission Staff to Comments on Proposed Competitive Transition Plan*. The report recommends some changes to the transition plan issued in January, including allowing open access to competitive service providers only for large industrial customers with loads averaging 5 megawatts or more rather than the original 2-megawatt load. Although the PSC ruled 2 years ago that open access was not in the State's best interest, study of the issue has continued in light of concerns about economic development. The report recommends another study, due in 2005, to determine whether competition would benefit all classes of customers.

Changes to the *AEO2002* projections as a result of State legislation and regulation were minor, with the exception of California. The changes that have resulted from California's legislative and regulatory developments throughout 2001 and their effects on the *AEO2002* forecasts are discussed in "Issues in Focus," pages 28-35.

Appliance Efficiency Standards

Since 1988, the U.S. Department of Energy (DOE) has promulgated numerous efficiency standards requiring the manufacture of appliances that meet or exceed minimum levels of efficiency as set forth by DOE test procedures. In 1987, Congress passed the National Appliance Energy Conservation Act (NAECA), which permitted DOE to establish test procedures and efficiency standards for 13 consumer products. Under the auspices of NAECA, DOE is responsible for revising the test procedures and efficiency levels as technology and economic conditions evolve over time.

From 1988 to 1995, DOE established and revised efficiency standards almost on an annual basis, as shown in Table 2. In 1995, however, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from establishing any new standards. As a result of the moratorium, no standards were promulgated from 1996 through July 2000. After a reevaluation of the standards program, DOE established a new process that allows for greater input from stakeholders by creating the Advisory Committee on Appliance Energy Efficiency Standards, which comprises technical experts representing the concerns of industry, environmentalists, and the general public.

Table 2. Effective dates of appliance efficiency standards, 1988-2007

Product	1988	1990	1992	1993	1994	1995	2000	2001	2003	2004	2005	2006	2007
Clothes dryers	X				X								
Clothes washers	X				X					X			X
Dishwashers	X				X								
Refrigerators and freezers		X		X				X					
Kitchen ranges and ovens		X											
Room air conditioners		X					X						
Direct heating equipment		X											
Fluorescent lamp ballasts		X									X		
Water heaters		X								X			
Pool heaters		X											
Central air conditioners and heat pumps			X									X	
Furnaces													
Central (>45,000 Btu per hour)			X										
Small (<45,000 Btu per hour)			X										
Mobile home		X											
Boilers			X										
Fluorescent lamps, 8 foot					X								
Fluorescent lamps, 2 and 4 foot (U tube)						X							
Commercial water-cooled air conditioners									X				
Commercial natural gas furnaces									X				
Commercial natural gas water heaters									X				

With input from stakeholders early in the promulgation process, it was believed that the rulemaking process would become more predictable, more timely, and less controversial. The refrigerator standard issued for July 2001, for example, was promulgated through a series of compromises in December 1996, allowing a later enforcement date but at a higher efficiency level. Achieving similar consensus among such disparate concerns as the natural gas and electric power industries and environmentalists may prove difficult, however, when multi-fuel products, such as water heaters, are considered for review. The debate over end-use efficiency versus total system efficiency is a lively one, with electric power and natural gas concerns generally disagreeing as to how efficiency and environmental benefits should be measured. In fact, the inability to create a single national home energy rating system (HERS) has shown that achieving consensus among these groups is difficult, signaling a continued debate as to how efficiency should be evaluated across fuel types.

In January 2001, DOE published final rules for several residential and commercial appliances, including residential water heaters, clothes washers, and central air conditioners and heat pumps, as well as commercial water-cooled cooling equipment and natural-gas-fired water heaters and furnaces. In July, however, DOE issued a Notice of Proposed Rulemaking (NOPR) withdrawing the final rulemaking for central air conditioners and heat pumps. The NOPR, which invited public comment through the end of September 2001, essentially replaced the 13 seasonal energy efficiency ratio (SEER) standard issued in January with a 12 SEER standard. The decision to lower the standard has brought legal action from the Natural Resources Defense Council (NRDC) and 3 States, which have sued DOE over the legality of withdrawing the original 13 SEER standard. For *AEO2002*, it is assumed that the 12 SEER standard will prevail in 2006, when it is scheduled to become effective.

Currently, DOE is evaluating standards for distribution transformers and residential furnaces and boilers. Because the *AEO2002* reference case includes only standards that have been finalized, with the effective dates and efficiency levels specified in the *Federal Register*, these efficiency standards are not included in the projections.

Production Tax Credit for Renewables

As part of EPACT, Congress established a tax credit of 1.5 cents per kilowatthour for electricity produced from new renewable generators using wind or closed-loop biomass energy sources. (Closed-loop biomass plants use feedstocks derived from “energy crops” grown specifically for energy production.) The credit is applicable for 10 years after a qualifying facility has been placed in service. Originally set to expire in 1999, the credit was extended by Congress to cover new units entering service by December 31, 2001. The tax credit was indexed to inflation and currently is worth 1.7 cents per kilowatthour.

In August 2001, the U.S. House of Representatives passed the Securing America’s Future Energy Act of 2001 (SAFE Act of 2001, currently bill H.R. 4). The SAFE Act would extend the renewable electricity production tax credit (PTC) for another 5 years, for new facilities on line through December 31, 2006, and would expand eligibility to open-loop biomass and landfill gas facilities. (Open-loop biomass plants use feedstocks derived as waste from other activities, such as agricultural residue, yard trimmings, and commercial wood waste.) Other similar proposals before Congress would extend the credit for various durations and expand it to different renewable generating technologies.

Because the legislation is still pending, it is not incorporated in the *AEO2002* reference case. Additional analysis indicates that the PTC provisions of H.R. 4 could have a significant effect on the targeted industries. By 2020, the tax credit could result in an additional 4 gigawatts of wind capacity (13 gigawatts with the PTC extension, compared with 9 gigawatts without), an additional 2 gigawatts of dedicated biomass capacity (4 gigawatts with the extension and expansion, compared with 2 gigawatts without), and an additional 1 gigawatt of landfill gas capacity (5 gigawatts with the extension and expansion, compared with 4 gigawatts without). If all the potential new renewable capacity were built, the nonhydroelectric renewable share of total U.S. electricity generation in 2020 could increase to 3.4 percent, as compared with 2.9 percent projected in the *AEO2002* reference case.

Heavy-Duty Vehicle Emissions and Diesel Fuel Quality Standards

In December 2000, the EPA finalized new regulations on heavy-duty engine and vehicle standards and highway diesel fuel sulfur control requirements [*4*]. The engine and vehicle standards will affect new heavy-duty vehicles sold in model years 2004, 2007, and 2010. In 2004, the standard requires that all new heavy-duty vehicles achieve a 40-percent reduction in emissions of nitrogen oxides (NO_x) and hydrocarbons (HC). In 2007, the rule requires 50 percent of new heavy-duty vehicles sold to meet significantly more stringent emissions standards. The 2007 standards require a 92-percent reduction in NO_X emissions and an 89-percent reduction in HC emissions from the 2004 standard. For model years 2007 through 2009, the EPA allows engine manufacturers flexibility in meeting the NO_X and HC standards, in that they are given the option to produce 100 percent of their engines to meet an average of the 2004 and 2007 NO_X and HC emissions standards. In 1998, the EPA signed consent decrees with several manufacturers of heavy-duty diesel engines, stating that they would produce engines to meet the 2004 emissions standards by October 2002. New standards for heavy-duty gasoline engines and vehicles will reduce both NO_X and HC emissions for all vehicles above 8,500 pounds gross vehicle weight not covered in the Tier 2 standards, beginning in 2004.

The new rule requires refiners and importers to produce highway diesel fuel meeting a 15 parts per million (ppm) maximum requirement, starting June 1, 2006; however, pipelines are expected to require refiners to provide diesel fuel with an even lower sulfur content, somewhat below 10 ppm, in order to compensate for contamination from higher sulfur products in the system and to provide a tolerance for testing. Diesel fuel meeting the new specification will be required at terminals by July 15, 2006, and at retail stations and wholesalers by September 1, 2006. Under a "temporary compliance option" (phase-in), up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010; the remaining 80 percent of the highway diesel fuel produced must meet the new 15 ppm maximum.

Analysis included in an EIA study conducted at the request of the EPA, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*, released in May 2001, indicated the possibility of a tight diesel market at the onset of the new 15-ppm sulfur maximum in June 2006 [*5*]. Given the EPA's assumptions for refinery equipment costs and return on investment, the EIA analysis concluded that increases in highway diesel costs of between 5.4 and 6.8 cents per gallon could be expected in the short run in Petroleum Administration for Defense Districts (PADDs) I through IV, and even higher increases would be expected if a shortfall in diesel supply occurred. The EPA has taken steps to monitor the ultra-low-sulfur diesel fuel (ULSD) supply situation. The EPA's Final Rulemaking requires refiners and importers expecting to produce highway diesel in 2006 to register with the EPA by December 31, 2001, and to provide annual updates of expected ULSD production capacity beginning in 2003.

EIA's study also included a longer term analysis of increases in the average annual end-use price of highway diesel, based on a range of different assumptions. Using a set of assumptions similar to those used by the EPA in its Regulatory Impact Analysis of the diesel rule, EIA estimated increases in the average U.S. end-use price ranging from 6.5 to 7.0 cents per gallon between 2007 and 2010. When a set of assumptions more consistent with previous industry analyses was used, price differentials ranged from 8.4 to 8.8 cents per gallon. The additional costs associated with complying with the new diesel regulation are included in the *AEO2002* reference case, based on the specific assumptions discussed in Appendix G.

In addition to the new highway diesel regulation, the EPA is in the early planning stages of new standards for diesel fuel used for other purposes, or "non-road" diesel. Since the specifics of the non-road standards have yet to be proposed by EPA, no changes in non-road diesel quality are reflected in the *AEO2002* reference case.

Relaxed Standard for Reformulated Gasoline in the Midwest

In June 2001, the EPA decided to modify the volatile organic compound (VOC) emissions standard for Federal reformulated gasoline (RFG) blended with ethanol. The EPA recognized that ethanol-blended RFG provides additional reductions in carbon monoxide emissions, which in turn reduce ground-level ozone formation. Because the VOC standards are also intended to reduce ground-level ozone formation, the standard for RFG with ethanol could be relaxed by the equivalent of 0.3 pounds per square inch (psi) Reid vapor pressure (Rvp) while maintaining the air quality benefits of the RFG program.

The EPA is moving cautiously, so far having granted the VOC waiver only to the Chicago-Milwaukee RFG market, which is the only market that requires RFG to be blended with ethanol. Both cities have had gasoline supply problems, due in part to the difficulty of refining the low-volatility blendstocks needed to blend RFG with ethanol. The EPA expects the VOC adjustment to increase gasoline supply in Chicago and Milwaukee.

Extension of the Rvp waiver for ethanol blending with RFG has been suggested before. In order to encourage the use of ethanol, conventional gasoline blended with ethanol is allowed by CAAA90 to have Rvp 1 psi higher than that of conventional gasoline. CAAA90 limited conventional gasoline volatility to 9 psi during the summer months, when ground-level ozone concentrations are most often at unhealthy levels. It also authorized the Administrator of the EPA to impose tighter Rvp standards in current or former nonattainment areas. An Rvp limit of 7.8 psi was imposed on many such areas, mainly those in warmer climates or at higher elevations. CAAA90 allows ethanol blends to exceed the applicable limit by 1 psi, provided that the gasoline blendstock complies with applicable limits and provided that the ethanol blend will not adversely affect emissions from vehicles certified to 1975 or later standards.

In February 1994, the EPA considered extending to RFG the 1-psi waiver for ethanol blends when it finalized standards for RFG. It noted that the VOC emission standards adopted for RFG might have the effect of excluding ethanol from the RFG oxygenate market. Forcing ethanol out of the RFG market might have increased dependence on foreign crude oil, which would be contrary to the Nation's energy policy. But the proposed waiver was expected to have little effect on petroleum imports as a result of the loss of energy content per gallon of gasoline that occurs when hydrocarbons are replaced with ethanol.

Of greater concern to the EPA was the potential for loss of air quality benefits if ethanol RFG blended under the waiver was mixed with non-ethanol RFG during automobile refueling. The EPA, estimating that such mixing could negate 40 to 50 percent of the VOC performance improvement associated with the RFG program, declined to extend the waiver to RFG at the time. The ethanol waiver decision was revisited after the emergence of supply shortages and price spikes in the Chicago-Milwaukee RFG market in the spring of 2000.

New Rule on Airborne Benzene

In March 2001, the EPA established its Mobile Source Air Toxics (MSAT) regulatory program. Twenty-one substances were placed on the MSAT list for future regulatory action. All MSAT substances are known or suspected to cause cancer or other serious illness. Benzene, formaldehyde, 1,3-butadiene, acetaldehyde, diesel particulate matter, and diesel exhaust organic gases are of the most concern. The EPA did not explicitly tighten emission standards for any of the MSAT substances, but it did put in place a regulation ensuring that future fuels will be at least as clean as today's fuels, according to emissions forecast from the EPA's Complex Model.

The new rule sets an allowable level of emissions (as predicted by the Complex Model) for each refiner's gasolines that is equal to the average predicted emissions of its output between 1998 and 2000. By 2020, the MSAT program is expected to reduce highway emissions of benzene, formaldehyde, 1,3-butadiene, and acetaldehyde by 67 to 76 percent relative to 1990 levels. Diesel particulate matter is projected to be reduced by 90 percent relative to 1990 levels.

One goal of the new rule is to prevent "backsliding" on airborne benzene. Benzene is emitted by evaporation of gasoline from vehicle fuel tanks and by incomplete combustion of gasoline. The RFG program gave refiners a choice of two benzene standards: an average of 0.95 percent by volume with an upper limit of 1.3 percent by volume, or an upper limit of 1.0 percent by volume with no average requirement. Benzene in conventional gasoline was regulated indirectly by the RFG program's anti-dumping toxic standards. Toxic standards for each refiner were set to the average emissions (as predicted by the Complex Model) for each batch of gasoline produced by that refiner in 1990. Under the new rule, conventional gasoline could average 1.3 percent benzene by volume.

In practice, refiners overcomplied with their limits. The new MSAT regulations aim to maintain current overcompliance levels of benzene in gasoline while forcing improvements in other emissions. Accordingly, refiners are now limited by the average emissions, as predicted by the Complex Model, of conventional gasoline and RFG that each produced between 1998 and 2000. A default baseline will also be available for refiners that did not produce gasoline for the U.S. market for 12 consecutive months between 1998 and 2000.

Low-Emission Vehicle Program

The Low-Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could opt in to the California program and achieve lower emissions levels than required by CAAA90. Both New York and Massachusetts chose to opt in to the LEVP, implementing the same mandates as California.

The LEVP was an emissions-based policy, setting sales mandates for three categories of low-emission vehicles according to their relative emissions of air pollutants: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The only vehicles certified as ZEVs by the California Air Resources Board (CARB) were dedicated electric vehicles [*6*].

The LEVP was originally scheduled to begin in 1998, with a requirement that 2 percent of the State's vehicle sales be ZEVs, increasing to 5 percent in 2001 and 10 percent in 2003. On November 5, 1998, the CARB amended the original LEVP to include ZEV credits for advanced technology vehicles. According to the CARB, qualifying advanced technology vehicles must be capable of achieving "extremely low levels of emissions on the order of the power plant emissions that occur from charging battery-powered electric vehicles, and some that demonstrate other ZEV-like characteristics such as inherent durability and partial zero-emission range" [*7*]. There are three components in calculating the ZEV credit, which vary by vehicle technology: (1) a baseline ZEV allowance, (2) a zero-emission vehicle-miles traveled (VMT) allowance, and (3) a low fuel-cycle emission allowance.

Further modifications proposed for the ZEV mandate in September 2000 were finalized in January 2001 [*8*]. The proposal was designed to maintain progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. The CARB proposal removed ZEV sales requirements before 2003 but maintained the 2003 required ZEV sales goal of 10 percent and required a gradual increase of ZEV sales to 16 percent by 2018. The number of vehicles included in the estimation of required ZEV sales was also increased, to include small light-duty trucks.

The proposal also provides manufacturers flexibility in meeting the goal through increased vehicle credits and greater allowances for partial ZEVs (PZEVs) and advanced technology ZEVs (AT-PZEVs). ZEVs will earn 1.25 credits per vehicle before 2006, and PZEVs will receive a phase-in multiplier credit of 4, 2, and 1.3 per vehicle for 2004, 2005, and 2006, respectively. Extra credits will also be allowed for ZEVs with extended range and/or reduced fueling times.

The baseline PZEV allowance potentially can provide up to 0.2 credit if the advanced technology vehicle meets the following standards: (1) super-ultra-low-emission vehicle (SULEV) standards, which approximate the emissions from power plants associated with recharging electric vehicles; (2) on-board diagnostics (OBD) requirements for indicators on the dashboard that light up when vehicles are out of emissions compliance levels; (3) a 150,000-mile warranty on emission control equipment; and (4) evaporative emissions requirements in California, which prevent emissions during refueling. The modifications allow a maximum of 6 percentage points of the ZEV mandate sales requirement to be met by PZEVs.

The AT-PZEV allowance will allow a maximum 0.6 credit if the vehicle is capable of some all-electric operation (to a range of at least 20 miles), or if the vehicle has ZEV-like equipment on board, such as regenerative braking, advanced batteries, or an advanced electric drive train. AT-PZEVs can satisfy up to 50 percent of the pure ZEV sales requirement. The remaining mandated ZEV sales must be electric vehicles or hydrogen fuel cell vehicles.

An emission allowance was also made for vehicle fuels with low fuel-cycle emissions used in advanced technology vehicles. A maximum of 0.2 credit is provided for vehicles that use fuels which emit no more than 0.01 gram of nonmethane organic gases per mile, based on the grams per gallon and the fuel efficiency of the vehicle.

AEO2002 assumes that Massachusetts, New York, Maine, and Vermont will also adopt the California LEVP mandates.

Proposed Energy Legislation

Comprehensive energy-related legislation has been proposed in both the House and the Senate. H.R. 4, Securing America's Energy Future Act of 2001 (Tauzin), which largely parallels the National Energy Policy Plan (NEPP) [*9*], was passed in the House of Representatives in August 2001. The proposed Republican bill in the Senate, S. 388, the National Energy Security Act of 2001 (Murkowski), is similar to H.R. 4; however, the principal Senate bill, S. 597, the Comprehensive and Balanced Energy Policy Act of 2001 (Bingaman), differs from the NEPP and H.R. 4 in several respects. Perhaps the most notable difference is that the NEPP and H.R. 4 permit oil and natural gas drilling in Alaska's

Arctic National Wildlife Refuge (ANWR), whereas S. 597 does not. Neither proposal requires changes to vehicle fuel economy standards, although H.R. 4 requires the Secretary of Transportation to prescribe standards for light trucks manufactured from 2004 to 2010.

While S. 597 and H.R. 4 have dozens of provisions that are similar, they differ greatly in emphasis. H.R. 4 contains numerous tax incentives for energy production; S. 597 does not. Also, S. 597 contains numerous provisions on electricity deregulation that do not appear in H.R. 4. As of mid-November 2001, it appeared unlikely that there would be a vote on the Senate bill before the end of 2001. Consequently, the *AEO2002* forecasts do not include any of the provisions of the proposed legislation. A number of the proposals contained in S. 597, H.R. 4, and the NEPP, as described in the summaries of the bills and in the NEPP, are listed below. Many of the NEPP proposals would require new legislation, and others would depend on budget authority.

S. 597

- Establishes a National Commission on Energy and Climate Change and an Interagency Working Group on Clean Energy Technology Transfer
- Authorizes the States to develop regional coordination of energy infrastructure
- Mandates periodic reviews of regulations to identify barriers to market entry for emerging energy technologies
- Amends the Federal Power Act to establish the Electric Reliability Organization
- Establishes a Public Benefits Fund
- Amends the Rural Electrification Act of 1936 to authorize electrification grants for rural and remote communities
- Amends the Energy Policy Act of 1992 to mandate a comprehensive Indian energy program and amends the Department of Energy Organization Act to establish an Office of Indian Energy Policy and Programs
- Directs the Federal Trade Commission to prescribe disclosure requirements regarding energy sources used to generate electricity and specified consumer protections and privacy
- Amends the Federal Power Act to require the FERC to establish a wholesale electricity market data information system and wholesale electric energy rates in the Western energy market
- Prescribes guidelines governing renewable energy resources, distributed generation facilities, and hydroelectric relicensing
- Directs the Secretary of Energy to assess cost and performance goals for a national coal-based technology development and applications program and to implement a power plant improvement initiative program
- Amends the Atomic Energy Act of 1954 to revise indemnification and liability guidelines (the Price-Anderson Amendments Act of 2001)
- Sets a deadline for a specified Outer Continental Shelf oil and gas lease sale. Mandates an accelerated research and development program regarding pipeline integrity for natural gas and hazardous liquids
- Prescribes guidelines for statutory mechanisms that increase vehicle fuel efficiency or provide vehicle alternatives in order to limit demand for petroleum products by light-duty vehicles
- Amends the Energy Policy and Conservation Act to revise alternative fuel requirements for Federal fleets
- Establishes a Federal Energy Bank and a High Performance Schools Program
- Delineates goals for enhanced research and development programs that target energy efficiency, renewable energy, fossil energy, nuclear energy, and fundamental energy science (Energy Science and Technology Enhancement Act)
- Directs the Secretary of Energy to establish national energy research and development advisory boards; monitor workforce trends pertaining to skilled technical personnel supporting energy technology industries; establish traineeship grant programs for technically skilled personnel; and develop employee training guidelines to support electric supply system reliability and safety.

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- Reauthorizes Federal energy conservation programs with respect to Federal energy savings performance contracts, automobile fuel economy, nuclear energy, high ozone season reformulated gasoline and gasoline blendstock requirements, MTBE contamination from underground storage tanks, oil and gas pipeline routes, the burning of post-consumer carpet in cement kilns as an alternative energy source, and other specified matters

- Sets goals for energy research, development, and commercial application programs (Comprehensive Energy Research and Technology Act of 2001)
- Directs the Secretary of Energy to establish a competitive grant pilot program for State and local governments and metropolitan transportation authorities to implement an alternative fuel vehicle acquisition program (Alternative Fuel Vehicle Acceleration Act of 2001)
- Directs the Secretary of Energy to establish grant and cooperative agreement programs for alternative fuel, ultra-low-sulfur diesel, and fuel-cell-powered school buses (Clean Green School Bus Act of 2001)
- Authorizes the Secretary of Energy to establish the Next Generation Lighting Initiative (Next Generation Lighting Initiative Act)
- Earmarks funds for the U.S. EPA's Office of Air and Radiation (Environmental Protection Agency Office of Air and Radiation Authorization Act of 2001)
- Amends the Spark M. Matsunaga Hydrogen Research, Development, and Demonstration Act of 1990 to direct the Secretary of Energy to conduct a hydrogen technology transfer program to increase the global market for hydrogen technologies (Robert S. Walker and George E. Brown, Jr. Hydrogen Energy Act of 2001)
- Authorizes appropriations for bioenergy research and development programs and biofuels energy systems (Bioenergy Act of 2001)
- Directs the Secretary of Energy to support or conduct a program to maintain the Nation's human resource investment and infrastructure in nuclear sciences and engineering; an advanced fuel recycling technology research and development program to promote the availability of proliferation-resistant fuel recycling technologies; a Nuclear Energy Research Initiative; and a Nuclear Energy Plant Optimization research and development program (Department of Energy University Nuclear Science and Engineering Act)
- Directs the Secretary of Energy to implement research and development programs pertaining to unconventional and ultra-deepwater natural gas and petroleum exploration and production technologies in areas currently available for Outer Continental Shelf leasing (Natural Gas and Other Petroleum Research, Development, and Demonstration Act of 2001)
- Directs the Secretary of Energy to develop a plan for U.S. construction of a magnetic fusion burning plasma experiment and a Fusion Energy Sciences Program
- Authorizes appropriations for the “Spallation Neutron Source” at Oak Ridge National Laboratory
- Amends the Internal Revenue Code with respect to specified energy conservation credits and deductions (Energy Tax Policy Act of 2001)
- Directs the Secretary of Energy to implement a prescribed program of cost and performance goals for specified 5-year periods, entailing research, development, demonstration, and commercial application of clean coal technologies (Clean Coal Power Initiative Act of 2001)
- Mandates Federal agency reports on whether rights-of-way for transportation across Federal lands of energy supplies or transmission of electricity can be authorized for new or additional capacity; and an inventory review of the wind, solar, coal, and geothermal power production potential of Federal lands (Energy Security Act)
- Mandates use of a specified bidding system for certain oil and gas lease sales located in the Western and Central Planning Area of the Gulf of Mexico (Royalty Relief Extension Act of 2001)
- Amends the Outer Continental Shelf Lands Act to prescribe guidelines for the payment in kind of oil and gas royalties to the United States and for royalty rate reductions for production declines at certain oil and gas wells, in order to spur marginal well production (Federal Oil and Gas Lease Management Improvement Demonstration Program Act of 2001)
- Amends the Geothermal Steam Act of 1970 to prescribe royalty reductions and to waive royalty requirements for certain geothermal energy leases
- Directs the Secretary of the Interior to establish a competitive oil and gas leasing program for the exploration and production of oil and gas resources of the Arctic Coastal Plain (Arctic Coastal Plain Domestic Energy Security Act of 2001).

Legislation and Regulations

NEPP

- Increases funding for energy efficiency programs, encouraging the development of fuel-efficient vehicles, creating tax credits to encourage consumer conservation, and expanding DOE conservation programs
- Expedites permitting for infrastructure improvements, expands research on reliable energy transmission, and removes regulatory barriers
- Expands the use of alternative and renewable energy such as wind, solar, biomass, and geothermal energy and provides for the safe expansion of cheap, clean, and safe nuclear energy
- Increases funding for clean coal research
- Directs DOE to undertake a review of existing energy efficiency and alternative and renewable energy research and development programs to assure that future program budget allocations are performance-based and modeled as public-private partnerships
- Provides $285 million for energy efficiency and renewable energy research and development
- Increases the industry cost share beyond the current average 50-percent share for some DOE programs, especially as research and development projects move closer to commercialization
- Enacts a new tax credit for investments in combined heat and power systems or shortens the depreciation life for combined heat and power projects
- Provides temporary income tax credits for the purchase of new hybrid and fuel cell vehicles, which would be available for all qualifying light vehicles, including cars, minivans, sport utility vehicles, and light trucks
- Proposes pipeline safety legislation that would significantly strengthen the enforcement of pipeline safety laws
- Directs the Secretaries of Energy and State to coordinate with the Secretary of the Interior and the FERC to work closely with Canada, the State of Alaska, Congress, and other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 States, including proposing to Congress any modifications to the Alaska Natural Gas Transportation Act of 1976 that may be necessary
- Proposes the development of legislation to implement electricity restructuring that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act
- Proposes the development of legislation to grant authority to obtain rights-of-way for electricity transmission lines only when absolutely necessary, with the goal of creating a reliable national transmission grid
- Provides several tax incentives to help increase the contribution that alternative and renewable energy makes to the Nation’s energy supply and extends the present 1.7 cents per kilowatthour tax credit for electricity produced from wind
- Expands tax credits for electricity produced using renewable technology, such as biomass; extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and other specified sources (for existing biomass facilities, the credit for electricity produced from the new sources is 1.0 cent per kilowatthour for 3 years of production, 2002-2004); and proposes a tax credit for electricity produced from co-firing biomass from new sources of 0.5 cent per kilowatthour for 3 years of production, 2002-2004
- Proposes a new 15-percent tax credit for individuals who purchase photovoltaic equipment or solar water heating equipment for use in an individual residence, up to a maximum credit of $2,000 for each type of equipment, which would be available for 2002-2007 for photovoltaic equipment and 2002-2005 for solar water heating equipment
- Proposes to extend the excise tax exemption for gasohol (ethanol mixed with motor fuels) and the income tax credit for ethanol used as fuel beyond 2007, when they are scheduled to expire
- Proposes to encourage an alternative source of energy near population centers by providing tax credits for energy produced from landfill gas, which would be available for energy produced from methane from regulated landfills that are required by the EPA to collect and flare methane and for unregulated landfills

- Supports reauthorization of the Hydrogen Energy Act
- Supports legislative or administrative reform of the hydropower licensing process to make the hydropower licensing process more clear and efficient, while preserving environmental goals
- Proposes that Congress authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR; and that any legislation should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment
- Urges Congress to pass legislation to use an estimated $1.2 billion of bid bonuses from leasing of ANWR for additional funding of research on alternative and renewable energy resources, including wind, solar, geothermal, and biomass
- Allows taxpayers (other than regulated utilities) to make deductible contributions to a nuclear decommissioning fund and permits nuclear decommissioning funds to accumulate the full amount needed for decommissioning
- Reauthorizes the Price-Anderson Act
- Directs the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power plants generators; propose mandatory reduction targets for emissions of sulfur dioxide, nitrogen oxides, and mercury; phase in the reductions over a reasonable period of time, similar to the successful acid rain reduction program established by CAAA90; provide regulatory certainty to encourage utilities to install newer, cleaner, more efficient systems; and provide market-based incentives, such as emissions trading credits, to help achieve the required results
- Directs the Secretary of the Interior to work with Congress to create a Royalties Conservation Fund that would earmark royalties from new oil and gas production in ANWR to fund land conservation efforts and would be used to eliminate the maintenance and improvements backlog on Federal lands
- Requests a fiscal year 2002 budget of $1.7 billion for the Low-Income Home Energy Assistance Program (LIHEAP), which would be an increase of $300 million from last year's non-emergency appropriation
- Proposes $1.2 billion in additional funding for the weatherization program over 10 years, roughly double the current level of spending.

Renewal of the Price-Anderson Act

The Price-Anderson Act, first passed in 1957 as an amendment to the Atomic Energy Act of 1954 and renewed three times since, will expire on August 1, 2002. The Act provides for payment of public liability claims in the event of a nuclear incident. Several bills have been introduced in the Senate to provide a 10-year extension to the Price-Anderson Act, including S. 388, the National Energy Security Act of 2001; S. 472, Nuclear Energy Electricity Supply Assurance Act of 2001; and S. 597, the Comprehensive and Balanced Energy Policy Act of 2001.

The goals of the Price-Anderson Act were to ensure that adequate funds would be available to the public to satisfy liability claims in the event of a nuclear accident and to permit private sector participation in nuclear energy by removing the threat of potentially enormous liability. Each nuclear reactor is required to be covered by the maximum liability insurance available from private insurers (currently $200 million). In addition, for each reactor, payment of up to $88 million into a supplemental insurance pool may be required if it is needed to cover damages in excess of the insurance coverage. Today, the total protection available in the event of a nuclear accident is over $9 billion. The Price-Anderson Act covers all currently licensed reactors throughout their lifetimes; however, new units will not be covered after August 1, 2002, unless Congress approves a renewal of the Act.

Analysis of North American Natural Gas Markets

On April 25, 2001, the Secretary of Energy, Spencer Abraham, asked EIA to conduct two studies of the North American natural gas market due to public concern about "tight supplies, volatile prices, and regional price disparities" during the winter of 2000-2001. The first study, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, released in May 2001 [*10*], examined the causes for high natural gas prices in the 2000-2001 winter, based on data available in the spring of 2001 and the prospects for the future as forecast in EIA's April 2001 *Short-Term Energy Outlook*. The study concluded that the high natural gas prices were caused by higher than normal demand; low natural gas prices in prior years, which resulted in a scarcity of wellhead gas production capacity relative to the high demand; a low level of working gas in storage at the beginning of the winter; and regional constraints on natural gas transmission.

The second study, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply*, released in December 2001 [*11*], updated the first analysis using more recent market data and provided a more detailed examination of the future prospects for U.S. natural gas markets. Four topics were specifically requested for consideration in the second study: the impact of drilling on wellhead gas supply, the potential for future imports of liquefied natural gas (LNG), the impact of removing access limitations to Federal lands and offshore areas on future natural gas supply, and improvements in data collection that would support a better understanding of natural gas markets.

Natural gas prices have declined since the winter of 2000-2001 due to lower demand and an increase in new wellhead supplies stimulated by the earlier high prices. The price reductions and record storage additions during 2001 indicate that the U.S. natural gas market has the self-correcting mechanisms associated with well-functioning markets, which bodes well for the market outlook, as domestic resources are expected to be substantial. The potential for foreign supplies is limited by U.S. capacity to import them. U.S. import capacity is expandable, given favorable economics.

Short-term price cycles are likely to be inevitable in a competitive market. When the industry operates at close to full capacity, small changes in supply and/or demand can cause significant market pressures that result in substantial price changes. The market experience in 2000-2001 shows that natural gas prices are vulnerable to short-term fluctuations in market conditions.

Large and unpredictable swings in natural gas prices impose considerable risk on investments in natural gas supply and consumption. An unpredictable price environment would shift the mix of natural gas supply investments away from long-term investments, such as LNG terminals and the Alaskan pipeline, toward short-term investments, such as conventional onshore drilling for natural gas. Such price behavior could also favor coal-fired facilities over natural-gas-fired facilities.

The construction of new LNG terminals and increased access to restricted areas would make more natural gas supply available, which could moderate future price increases. Increased access to Federal lands would increase the exploitable resource base in the Rocky Mountains by 29 trillion cubic feet and reduce the costs and development time for exploiting an additional 59 trillion cubic feet of Rocky Mountain resources. In the Outer Continental Shelf region, increased access would expand exploitable offshore resources by 58 trillion cubic feet. Under a high natural gas demand scenario, such as meeting a carbon dioxide emissions target, increased access to restricted areas is projected to increase domestic production in 2020 by about 1.1 trillion cubic feet over the reference case projection, while reducing wellhead natural gas prices by 15 cents per thousand cubic feet. When reference case assumptions are combined with alternative LNG costs in the cases with carbon dioxide emissions limits, LNG is projected to provide an incremental 0.9 trillion cubic feet of natural gas supply in 2020 at an average price that is 9 cents per thousand cubic feet lower than projected in the reference case.

With respect to natural gas data collection, EIA faces a number of challenges with regard to both the scope and quality of current natural gas data series. The collection of natural gas production and wellhead price data involves a challenge of timeliness, because monthly data submitted by the States and by the Minerals Management Service of the U.S. Department of Interior undergo numerous revisions before being finalized by the reporting agencies. The collection of natural gas consumption and end-use price data involves the challenge of completeness, because the restructuring of the natural gas industry, which began in the mid-1980s, expanded the number of market participants and changed business practices so that the current respondents sometimes do not know either the final use of the natural gas or its burnertip price. Efforts to correct these data inadequacies, which are crucial to serving the public need for timely, accurate, and complete natural gas data, are underway.

International Negotiations on Greenhouse Gas Reductions

The Framework Convention on Climate Change

As a result of increasing warnings by members of the climatological and scientific community about the possible harmful effects of rising greenhouse gas concentrations in the Earth's atmosphere, the Intergovernmental Panel on Climate Change was established by the World Meteorological Organization and the United Nations Environment Programme in 1988 to assess the available scientific, technical, and socioeconomic information in the field of climate change. A series of international conferences followed, and in 1990 the United Nations established the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change. After a series of negotiating sessions, the text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4, 1992.

The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." All signatories agreed to implement measures to mitigate climate change and prepare periodic emissions inventories. In addition, the developed country signatories agreed to adopt national policies with a goal of returning anthropogenic emissions of greenhouse gases to 1990 levels. The Convention excludes chlorofluorocarbons and hydrochlorofluorocarbons, which are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

In response to the Framework Convention, the United States issued the Climate Change Action Plan (CCAP) [*12*], published in October 1993, which consisted of a series of 44 actions to reduce greenhouse gas emissions. The actions included voluntary programs, industry partnerships, government incentives, research and development, regulatory programs including energy efficiency standards, and forestry actions. Greenhouse gases affected by the CCAP actions included carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons. At the time the CCAP was developed, the Clinton Administration estimated that the actions it enumerated would reduce total net emissions of these greenhouse gases in the United States to 1990 levels by 2000 [*13*]. That reduction was not achieved, however, and net U.S. greenhouse gas emissions increased from 1990 to 2000. Although the CCAP no longer stands as a unified program, some of its individual programs remain in effect.

The Conference of the Parties and the Kyoto Protocol

The Framework Convention established the Conference of the Parties (COP) to "review the implementation of the Convention and . . . make, within its mandate, the decisions necessary to promote the effective implementation." Moving beyond the 2000 target in the Convention, the first Conference of the Parties (COP-1) met in Berlin in 1995 and issued the Berlin mandate, an agreement to "begin a process to enable it to take appropriate action for the period beyond 2000." COP-2, held in Geneva in July 1996, called for negotiations on quantified limitations and reductions of greenhouse gas emissions and policies and measures for COP-3. From December 1 through 11, 1997, representatives from more than 160 countries met at COP-3 in Kyoto, Japan. In the resulting Kyoto Protocol to the Framework Convention, targets for greenhouse gas emissions were established for the developed nations—the Annex I countries—relative to their emissions levels in 1990 [*14*].

The Kyoto Protocol targets are to be achieved, on average, from 2008 through 2012, the first commitment period. The overall emissions reduction target for the Annex I countries is 5.2 percent below 1990 levels. Relative to 1990, the individual targets range from an 8-percent reduction for the European Union (EU) to a 10-percent increase for Iceland. The reduction target for the United States is 7 percent below 1990 levels. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The Protocol was opened for signature on March 16, 1998, for a 1-year period. It will enter into force 90 days after 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations, have deposited their instruments of ratification, acceptance, approval, or accession. By March 15, 1999, 84 countries had signed the Protocol, including all but two of the Annex I countries, Hungary and Iceland. As of October 26, 2001, 43 countries had ratified or acceded to the Protocol [*15*]; however, only one Annex I nation, Romania, has ratified the Protocol at this point.

Energy use is a natural focus of greenhouse gas reductions. In 1990, total greenhouse gas emissions in the United States were 1,678 million metric tons carbon equivalent, of which carbon dioxide emissions from the combustion of fossil fuels accounted for 1,352 million metric tons carbon equivalent, or 81 percent [*16*]. By 2000, total U.S. greenhouse gas emissions had risen to 1,906 million metric tons carbon equivalent, with 1,562 million metric tons carbon equivalent, or 82 percent, from fuel combustion. Because energy-related carbon dioxide emissions constitute such a large percentage of total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets.

The Kyoto Protocol includes a number of flexibility measures for compliance. Reductions in other greenhouse gases—methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—can offset carbon dioxide emissions [*17*]. "Sinks" that absorb carbon dioxide—forests, other vegetation, and soils—may also be used to offset emissions.

Emissions trading among the Annex I countries is also permitted under the Protocol, and groups of Annex I countries may jointly meet the total commitment of all the member nations either by allocating a share of the total reduction to each member or by trading emissions rights. Joint Implementation projects are also allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance sinks in other Annex I countries; however, it is indicated in the Protocol that trading and Joint Implementation are supplemental to domestic actions. The Protocol also establishes a Clean Development Mechanism (CDM), a program under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries if the projects lead to measurable, long-term emissions benefits.

The targets specified in the Protocol can be achieved on average over the first commitment period of 2008 to 2012 rather than in each individual year. No targets are established for periods after 2012, although the Conference of the Parties will initiate consideration of future commitments at least 7 years before the end of the first commitment period. Banking—carrying over emissions reductions that go beyond the target from one commitment period to some subsequent commitment period—is allowed. The Protocol indicates that each Annex I country must have made demonstrable progress in achieving its commitments by 2005.

In November 1998 at COP-4 in Buenos Aires, Argentina, a plan of action was adopted to finalize a number of the implementation issues at COP-6, held in the Netherlands on November 13 through 24, 2000, at The Hague. Negotiations at COP-5 in Bonn, Germany, from October 25 through November 5, 1999, focused on developing rules and guidelines for emissions trading, joint implementation, and the CDM; negotiating the definition and use of forestry activities and additional sinks; and understanding the basics of a compliance system, with an effort to complete the work at COP-6 [*18*].

The major goals of the COP-6 negotiations held in fall 2000 were to develop the concepts in the Protocol in sufficient detail that it could be ratified by enough Annex I countries to be put into force and to encourage significant action by the non-Annex I countries to meet the objectives of the Framework Convention [*19*]. The COP-6 negotiations focused on a range of technical issues, including emissions reporting and review, communications by non-Annex I countries, technology transfer, and assessments of capacity needs for developing countries and countries with economies in transition.

The COP-6 negotiations were suspended in November 2000, however, without agreement on a number of issues, including the appropriate amount of credit for carbon sinks, such as forests and farmlands, and the use of flexible mechanisms, such as international emissions trading and the CDM, to reduce the cost of meeting the global emissions targets [*20*]. COP-6 was rescheduled to resume in 2001 in Bonn, Germany [*21*].

COP-6 negotiations (Part 2) resumed in Bonn, Germany, on July 16, 2001, again focusing on developing the concepts in the Protocol in sufficient detail that it could be ratified by enough Annex I countries to be put into force. On July 23, 2001, 178 member nations of the United Nations Framework Convention on Climate Change reached an agreement, known as the Bonn Agreement, on the operational rulebook for the Kyoto Protocol.

The Bonn Agreement creates a Special Climate Change Fund and a Protocol Adaptation Fund to help developing countries adapt to climate change impacts, obtain clean technologies, and limit the growth in their emissions; allows developed nations to use carbon sinks to comply, in part, with their Kyoto emission reduction commitments; and establishes rules for the CDM, emissions trading, and Joint Implementation projects. The Bonn Agreement also emphasizes that domestic actions shall constitute a significant element of emission reduction efforts made by each Party, and establishes a Compliance Committee with a facilitative branch and an enforcement branch. In terms of compliance, for every ton of gas that a country emits over its target, it will be required to reduce an additional 1.3 tons during the Protocol's second commitment period, which starts in 2013.

The Bonn Agreement was forwarded for official adoption at COP-7, which was held in Marrakech, Morocco, from October 29 to November 9, 2001. On November 9, 2001, 165 nations reached agreement on a number of implementation rules for the Bonn Agreement and the Kyoto Protocol. The agreement, referred to as the "Marrakech Accords," covered a number of issues, including rules for international emissions trading; a compliance regime to enforce emissions targets, with the issue of legally binding targets deferred to a future Conference of the Parties; fungible accounting rules that allow emissions trading among Annex I countries, CDM and Joint Implementation mechanisms; and a new emission unit for carbon "sinks" that cannot be banked for future commitment periods [*22*]. COP-8 is scheduled for October 23 to November 1, 2002, with India as a possible location [*23*]. COP-8 will, among other things, review the adequacy of commitments under the Kyoto Protocol, including those of developing countries, with the intent of framing the issue for discussion at COP-9.

The Bush Administration has indicated that it has no objection to the participation of other countries in the Kyoto Protocol, even without U.S. participation, and has indicated that it intends to develop U.S. alternatives to the Kyoto Protocol, including the National Climate Change Technology Initiative [*24*]. As noted above, the Protocol can enter into force with ratification by enough Annex I nations to account for 55 percent of total Annex I carbon dioxide emissions in 1990. Because the United States accounted for about 35 percent of 1990 Annex I carbon dioxide emissions, the Protocol can enter into force without ratification by the United States.